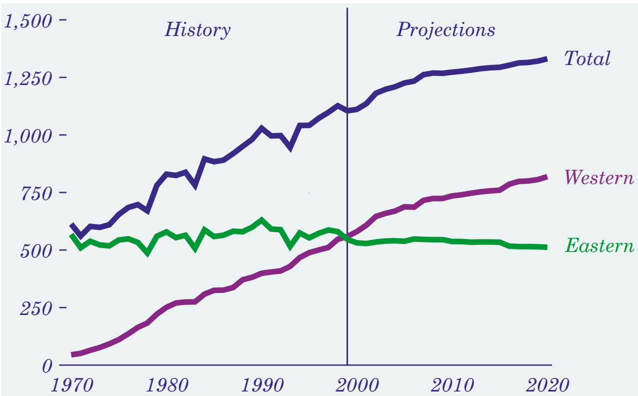
Emissions Caps Lead to More Use of Low-Sulfur Coal From Western Mines

Figure 113. Coal production by region, 1970-2020 (million short tons)



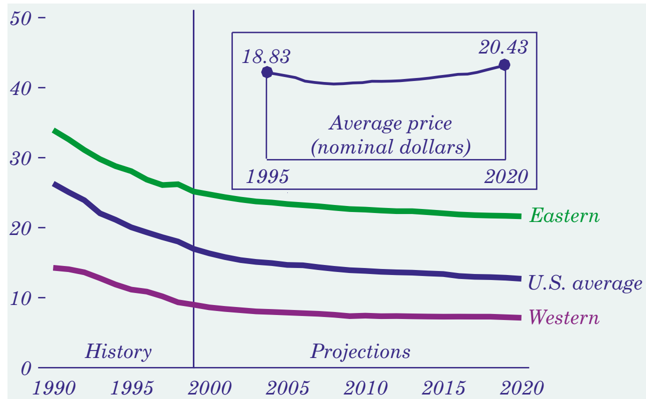
Continued improvements in mine productivity (which have averaged 6.7 percent per year since 1979) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, are projected to yield increasing coal demand, but the demand is subject to an overall sulfur emissions cap from CAAA90, which encourages progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent lower sulfur dioxide emissions than the use of many types of higher sulfur eastern coal. As coal demand grows in the forecast, however, new coal-fired generating capacity is required to use the best available control technology: scrubbers or advanced coal technologies that can reduce sulfur emissions by 90 percent or more. Thus, even as the demand for low-sulfur coal is projected to grow, there are still expected to be market opportunities for low-cost higher sulfur coal throughout the forecast.

From 1999 to 2020, high- and medium-sulfur coal production is projected to decline from 616 to 592 million tons (0.2 percent per year), and low-sulfur coal production is projected to rise from 490 to 740 million tons (2.0 percent per year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production is expected to continue its historical growth, reaching 819 million tons in 2020 (Figure 113), but its annual growth rate is projected to fall from the 9.3 percent achieved between 1970 and 1999 to 1.8 percent in the forecast period.

Minemouth Coal Prices Continue To Fall in the Projections

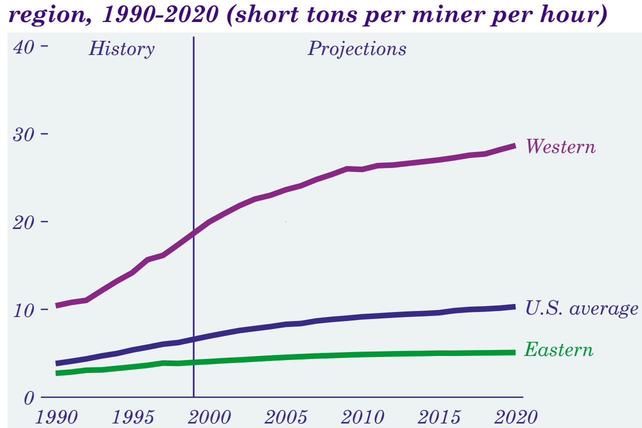
Figure 114. Average minemouth price of coal by region, 1990-2020 (1999 dollars per short ton)



Minemouth coal prices declined by $5.80 per ton (in 1999 dollars) between 1970 and 1999, and they are projected to decline by 1.4 percent per year, or $4.28 per ton, between 1999 and 2020 (Figure 114). The price of coal delivered to electricity generators, which declined by approximately 95 cents per ton between 1970 and 1999, is projected to fall to $19.45 per ton in 2020—a 1.1-percent annual decline.

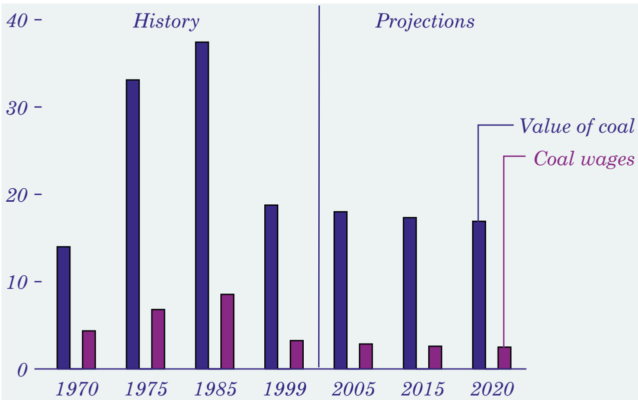
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is expected to be maintained throughout the forecast. Average U.S. labor productivity (Figure 115) is projected to follow the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 115. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)



Labor Cost Contribution to Total Coal Prices Continues To Decline

Figure 116. Labor cost component of minemouth coal prices, 1970-2020 (billion 1999 dollars)



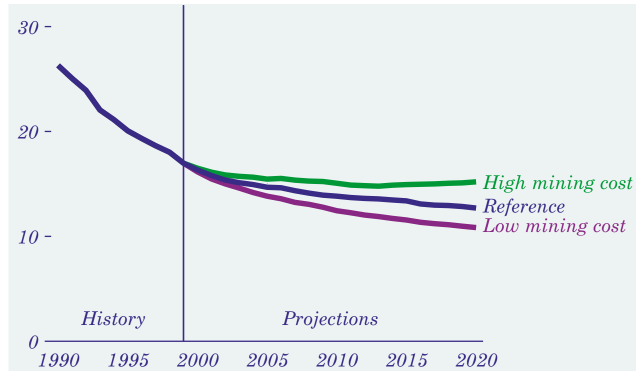
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity is also expected to be influenced by changing regional production shares. Competition from very low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been successfully tested in all U.S. Census divisions except New England and the Mid-Atlantic, and its use in eastern markets is projected to increase.

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Continued penetration of technologies for extracting and hauling large volumes of coal in both surface and underground mining suggests that further reductions in mining cost are likely. Improvements in labor productivity have been, and are expected to remain, the key to lower coal mining costs.

As labor productivity improved between 1970 and 1999, the average number of miners working daily fell by 2.2 percent per year. With improvements expected to continue through 2020, a further decline of 1.2 percent per year in the number of miners is projected. The share of wages (excluding irregular bonuses, welfare benefits, and payroll taxes paid by employers) in minemouth coal prices [*92*], which fell from 31 percent to 17 percent between 1970 and 1999, is projected to decline to 15 percent by 2020 (Figure 116).

High Labor Cost Assumption Leads to Lower Production in the East

Figure 117. Average minemouth coal prices in three mining cost cases, 1990-2020 (1999 dollars per short ton)



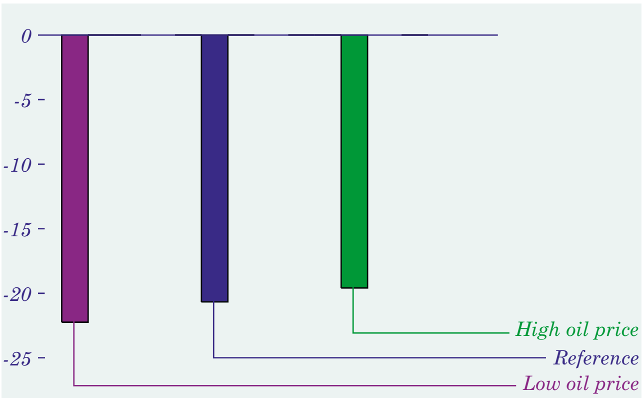
Alternative assumptions about future regional mining costs affect the projections for market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, projected minemouth prices, delivered prices, and the resulting regional coal production levels vary with changes in projected mining costs.

Productivity is assumed to increase by 2.2 percent per year through 2020 in the reference case, while wage rates and equipment costs are constant in 1999 dollars. The national minemouth coal price is projected to decline by 1.4 percent per year to $12.70 per ton in 2020 (Figure 117).

In the low mining cost case, productivity is assumed to increase by 3.7 percent per year, and real wages and equipment costs are assumed to decline by 0.5 percent per year [*93*]. As a result, the average minemouth price is projected to fall by 2.1 percent per year to $10.84 per ton in 2020 (14.6 percent less than projected in the reference case). Eastern coal production is projected to be 4 million tons higher in the low mining cost case than in the reference case in 2020, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity is assumed to increase by only 0.6 percent per year, and real wages and equipment costs are assumed to increase by 0.5 percent per year. Consequently, the average minemouth price of coal is projected to fall by 0.5 percent per year to $15.18 per ton in 2020 (19.5 percent higher than in the reference case). Eastern production in 2020 is projected to be 13 million tons lower in the high mining cost case than in the reference case.

Transportation Costs Are a Key Factor for Coal Markets

Figure 118. Projected change in coal transportation costs in three cases, 1999-2020 (percent)

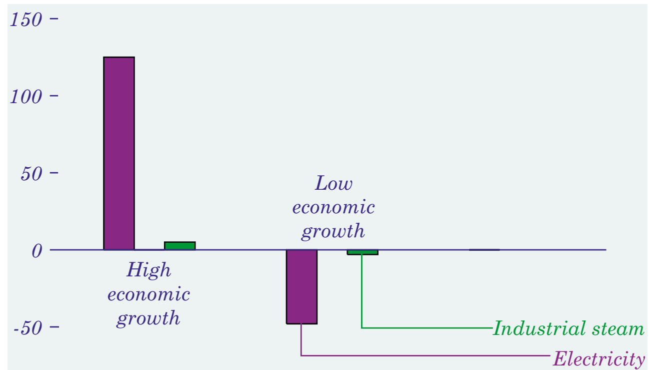


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation costs (Figure 118), but transportation fuel efficiency also grows with other productivity improvements in the forecast. As a result, in the reference case, average coal transportation rates are projected to decline by 1.1 percent per year between 1999 and 2020. Historically, the most rapid declines in coal transportation costs have occurred on routes originating in coalfields that have had the greatest declines in real minemouth prices. Railroads are likely to reinvest profits from increasing coal traffic to reduce transportation costs and, thus, expand the market for such coal. Therefore, coalfields that are most successful at improving productivity and lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Assuming that mines in the Powder River Basin will complete needed expansions of their train-loading capacities, western coal is expected to be able to meet the increase in demand expected with the advent of Phase 2 of CAAA90, which became effective on January 1, 2000. The transition will require more low-sulfur coal than was projected in *AEO2000*, because scrubber retrofits are expected to be made at a slower pace in *AEO2001*. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary.

Higher Economic Growth Would Favor Coal for Electricity Generation

Figure 119. Projected variation from reference case projections of coal demand in two economic growth cases, 2020 (million short tons)

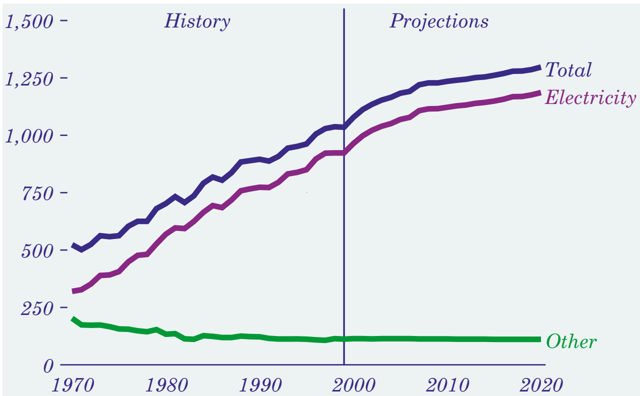


A strong correlation between economic growth and electricity use accounts for the variation in coal demand projections across the economic growth cases (Figure 119), with domestic coal consumption in 2020 projected to range from 1,245 to 1,426 million tons in the low and high economic growth cases, respectively. Of the difference, coal use for electricity generation is projected to make up 173 million tons. The difference in total projected coal production between the two economic growth cases is 182 million tons, of which 148 million tons (81 percent) is projected to be western production. Although western coal must travel up to 2,000 miles to reach some of its markets, it is expected to remain competitively priced in all regions except the Northeast when its transportation costs are added to its low minemouth price and low sulfur allowance cost.

Changes in world oil prices affect the costs of energy (both diesel fuel and electricity) for coal mining. In the low and high oil price cases, the average prices of coal delivered to electricity generators are projected to be 0.8 percent lower and 0.2 percent higher, respectively, in 2020 than projected in the reference case. The low world oil price case projects 79 million tons less coal use in 2020 than the high world oil price case. Low oil prices encourage electricity generation from oil, whereas high oil prices encourage coal consumption. The higher projection for coal consumption in the high oil price case is attributable to the electricity generation sector, which is projected to account for virtually all of the increase.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 120. Electricity and other coal consumption, 1970-2020 (million short tons)



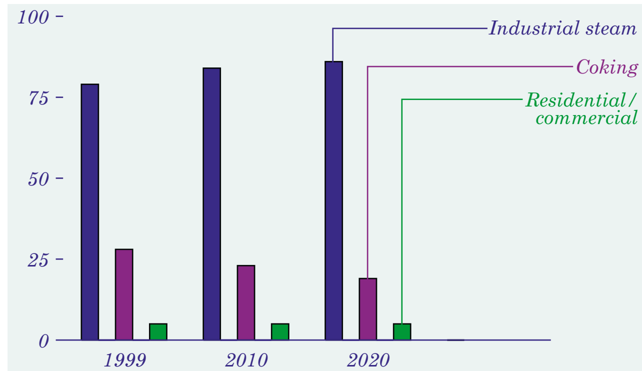
Domestic coal demand is projected to increase by 262 million tons in the reference case forecast, from 1,035 million tons in 1999 to 1,297 million tons in 2020 (Figure 120), because of projected growth in coal use for electricity generation. Coal demand in other domestic end-use sectors is projected to decline.

Coal consumption for electricity generation (excluding cogeneration) is projected to increase from 923 million tons in 1999 to 1,186 million tons in 2020 as the utilization of existing coal-fired generation capacity increases and, in later years, new capacity is added. The average utilization rate is projected to increase from 68 percent in 1999 to 83 percent in 2020. Because coal consumption (in tons) per kilowatthour generated is higher for subbituminous and lignite than for bituminous coals, the shift to western coal is projected to increase the tonnage per kilowatthour of generation in the midwestern and southeastern regions. In the East, generators are expected to shift to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per ton.

Although coal is projected to maintain its fuel cost advantage over both oil and natural gas, gas-fired generation is expected to be the most economical choice for construction of new power generation units in most situations, when capital, operating, and fuel costs are considered. Between 2005 and 2020, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Industrial Steam Coal Use Rises, But Demand for Coking Coal Declines

Figure 121. Projected coal consumption in the industrial and buildings sectors, 2010 and 2020 (million short tons)



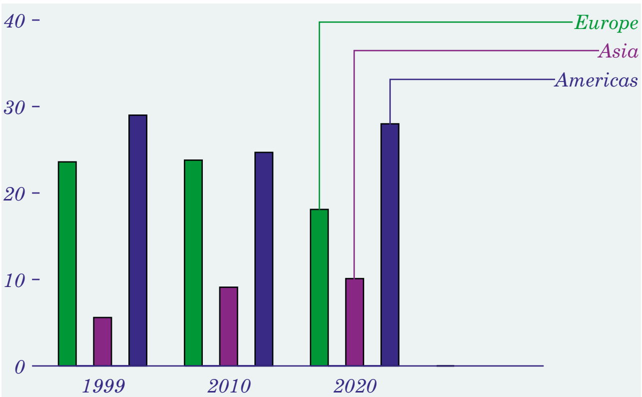
In the non-electricity sectors, a projected increase of 7 million tons in industrial steam coal consumption between 1999 and 2020 (0.5-percent annual growth) is expected to be offset by a decrease of 9 million tons in coking coal consumption (Figure 121). Increasing consumption of industrial steam coal is projected to result primarily from greater use of existing coal-fired boilers in energy-intensive industries.

The projected decline in domestic consumption of coking coal results from the expected displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.9 percent per year through 2020, but domestic production of coking coal is expected to be stabilized, in part, by sustained levels of export demand.

Although total energy consumption in the combined residential and commercial sectors is projected to grow by 1.3 percent per year, most of the growth is expected to be captured by electricity and natural gas. Coal consumption in the residential and commercial sectors is projected to remain constant, accounting for less than 1 percent of total U.S. coal demand in the forecast.

U.S. Coal Exports to Europe and Asia Are Projected To Remain Stable

Figure 122. Projected U.S. coal exports by destination, 2010 and 2020 (million short tons)



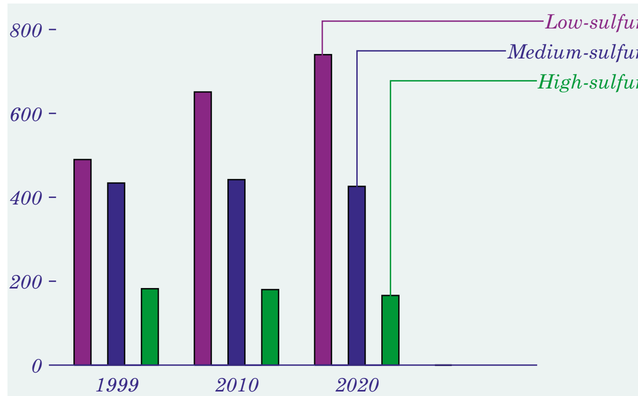
U.S. coal exports declined sharply between 1998 and 1999, from 78 million tons to 58 million tons, but are projected to remain relatively stable over the forecast horizon, settling at 56 million tons by 2020 (Figure 122). Australian and South African coal export prices dropped substantially in 1999, displacing U.S. coal exports to Europe and Asia. Price cuts by Australia, the world's leading coal exporter, were attributed to both strong productivity growth and a favorable exchange rate against the U.S. dollar.

The U.S. share of total world coal trade is projected to decline from 11 percent in 1999 to 8 percent by 2020 as international competition intensifies and demand for coal imports in Europe and the Americas grows more slowly or declines. From 1999 to 2020, U.S. steam coal exports are projected to decline slightly, from 26 million tons to 22 million tons, despite substantial projected growth in world steam coal trade. Steam coal exports from Australia, South Africa, China, and Indonesia are expected to increase in response to growing import demand in Asian countries, and increasing exports from South Africa are expected to displace some U.S. exports to Europe.

U.S. coking coal exports are projected to increase slightly, from 32 million tons in 1999 to 34 million tons in 2020. A small increase in the world trade in coking coal is expected, primarily in Asia. Australia is expected to capture an increasing share of the international market for coking coal because of its proximity to Asian importers and its ample reserves of coking coal.

Low-Sulfur Coal Continues To Gain Share in the Generation Market

Figure 123. Projected coal production by sulfur content, 2010 and 2020 (million short tons)



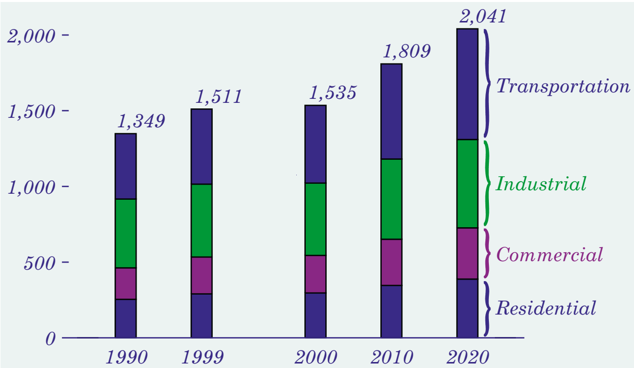
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which took effect on January 1, 2000, tightens the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas. The program affects existing utility units serving generators over 25 megawatts capacity and all new utility units [*94*].

With relatively modest capital investments many generators can blend very low sulfur subbituminous and bituminous coal in Phase 1 affected boilers. Such fuel switching often generates sulfur dioxide allowances beyond those needed for Phase 1 compliance, and the excess allowances generated during Phase 1 were banked for use in Phase 2 or sold to other generators. (The proceeds of such sales can be seen as further reducing fuel costs for the seller.) In the forecast, fuel switching for regulatory compliance and for cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 123). The main sources of low-sulfur coal are the Central Appalachian, Powder River Basin, and Rocky Mountain regions, as well as coal imports.

Coal users may incur additional costs in the future if environmental problems associated with nitrogen oxides, particulate emissions, and possibly carbon dioxide emissions from coal combustion are monetized and added to the costs of coal combustion.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 124. Projected carbon dioxide emissions by sector, 2000, 2010, and 2020 (million metric tons carbon equivalent)



Carbon dioxide emissions from energy use are projected to increase on average by 1.4 percent per year from 1999 to 2020, to 2,041 million metric tons carbon equivalent (Figure 124), and emissions per capita are projected to grow by 0.6 percent per year.

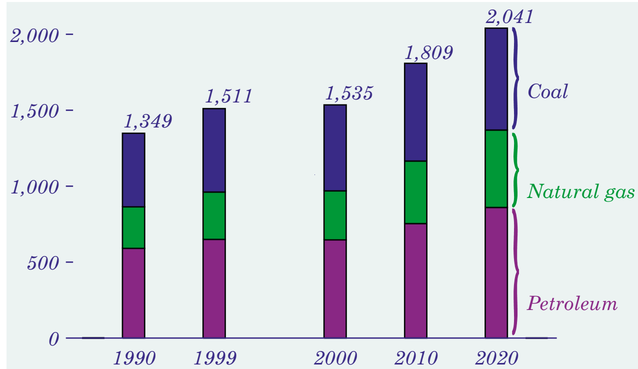
Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.4 percent per year, reflecting the ongoing trends of electrification and penetration of new appliances and services. Significant growth in office equipment and other uses is also projected in the commercial sector, but growth in consumption—and in carbon dioxide emissions, which are projected to increase by 1.6 percent per year—is expected to be moderated by slowing growth in floorspace.

In the transportation sector, carbon dioxide emissions are projected to grow at an average annual rate of 1.8 percent as a result of projected increases in vehicle-miles traveled and freight and air travel, combined with small increases in average light-duty fleet efficiency. Industrial emissions are projected to grow by only 0.9 percent per year, as shifts to less energy-intensive industries and efficiency gains are projected to moderate growth in energy use.

In all sectors, potential growth in carbon dioxide emissions is expected to be moderated by efficiency standards, voluntary efficiency programs, and improvements in technology. Carbon dioxide mitigation programs, further improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Petroleum Products Lead Carbon Dioxide Emissions From Energy Use

Figure 125. Projected carbon dioxide emissions by fuel, 2000, 2010, and 2020 (million metric tons carbon equivalent)



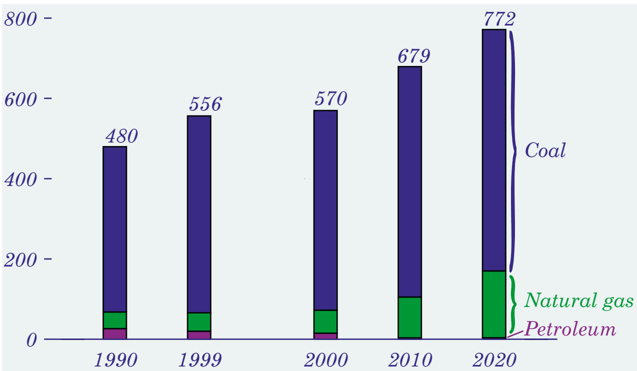
Petroleum products are the leading source of carbon dioxide emissions from energy use. In 2020, petroleum is projected to account for 860 million metric tons carbon equivalent, a 42-percent share of the projected total (Figure 125). About 82 percent (705 million metric tons carbon equivalent) of the emissions from petroleum use are expected to result from transportation fuel use, which could be lower with less travel or more rapid development and adoption of higher efficiency or alternative-fuel vehicles.

Coal is the second leading source of carbon dioxide emissions, projected to produce 671 million metric tons carbon equivalent in 2020, or 33 percent of the total. The coal share is projected to decline from 36 percent in 1999, because coal consumption is expected to increase at a slower rate through 2020 than consumption of petroleum and natural gas, the sources of virtually all other energy-related carbon dioxide emissions. Most of the increases in emissions from coal use result from electricity generation.

In 2020, natural gas use is projected to produce a 25-percent share of total carbon dioxide emissions, 510 million metric tons carbon equivalent. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at average annual rates of 2.3 and 2.4 percent; however, natural gas produces only half the carbon dioxide emissions of coal per unit of input. Average emissions from petroleum use are between those for coal and natural gas. Electricity generation from renewable fuels and nuclear power, which emit little or no carbon dioxide, is expected to mitigate the projected increase in carbon dioxide emissions.

Electricity Use Is Another Major Cause of Carbon Dioxide Emissions

Figure 126. Projected carbon dioxide emissions from electricity generation by fuel, 2000, 2010, and 2020 (million metric tons carbon equivalent)



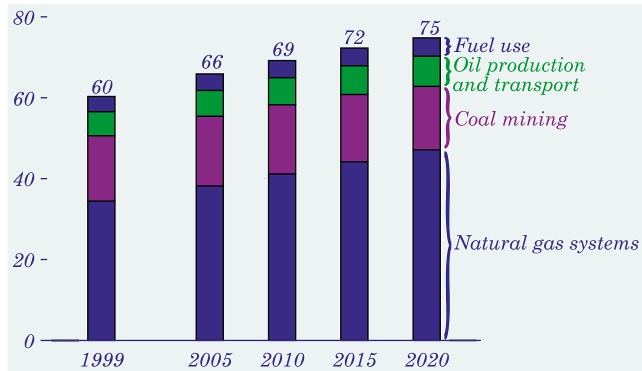
Electricity generation is a major source of carbon dioxide emissions. Although electricity produces no emissions at the point of use, generation (excluding cogeneration) accounted for 37 percent of total carbon dioxide emissions in 1999, and its share is expected to increase to 38 percent in 2020. Coal is projected to account for 47 percent of electricity generation in 2020 (excluding cogeneration) and to produce 78 percent of electricity-related carbon dioxide emissions (Figure 126). In 2020, natural gas is projected to account for 33 percent of electricity generation (excluding cogeneration) but only 22 percent of electricity-related carbon dioxide emissions.

Between 1999 and 2020, 26 gigawatts of nuclear capacity is projected to be retired, resulting in a 21-percent decline in nuclear generation. To make up for the loss of nuclear capacity and meet rising demand, 385 gigawatts of new fossil-fueled capacity (excluding cogeneration) is projected to be needed. Increased generation from fossil fuels is expected to raise carbon dioxide emissions from electricity generation (excluding cogeneration) by 215 million metric tons carbon equivalent, or 39 percent, from 1999 levels. Generation from renewable technologies (excluding cogeneration) is projected to increase by 43 billion kilowatthours, or 12 percent, between 1999 and 2020 but is not expected to be sufficient to offset the projected increase in generation from fossil fuels.

The projections include announced activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, but they do not include offset activities, such as reforestation.

Moderate Growth in Methane Emissions Is Expected

Figure 127. Projected methane emissions from energy use, 2005-2020 (million metric tons carbon equivalent)



Methane emissions from energy use are projected to increase at an average rate of 1.0 percent per year from 1999 to 2020, somewhat slower than the 1.4-percent projected growth rate for carbon dioxide emissions. Based on global warming potential, methane is the second largest component of U.S. man-made greenhouse gas emissions after carbon dioxide, and it is one of the six gases covered in the Kyoto Protocol. In 1999, methane accounted for 9 percent of total U.S. greenhouse gas emissions of 1,833 million metric tons carbon equivalent. About a third of U.S. methane emissions are related to energy activities, mostly from energy production and transportation and to a much smaller extent from fuel combustion. Other sources of methane emissions include waste management, agriculture, and industrial processes.

Much of the projected increase in energy-related methane emissions is tied to increases in oil and gas use (Figure 127). The fugitive methane emissions that occur during natural gas production, processing, and distribution are expected to increase, despite declines in the average rate of emissions per unit of production. Emissions related to oil production and, to a lesser extent, refining and transport are also expected to increase. Coal-related methane emissions are expected to decline, with coal production from methane-intensive underground mining projected to remain flat over the forecast period while progress in the recovery of vented gas continues. About 6 percent of methane emissions in 1999 resulted from wood and fossil fuel combustion. A 20-percent increase is projected by 2020, with residential use of wood as a fuel expected to remain at about its 1999 level.

Scrubber Retrofits Will Be Needed To Meet Sulfur Emissions Caps

Figure 128. Projected sulfur dioxide emissions from electricity generation, 2000-2020 (million tons)

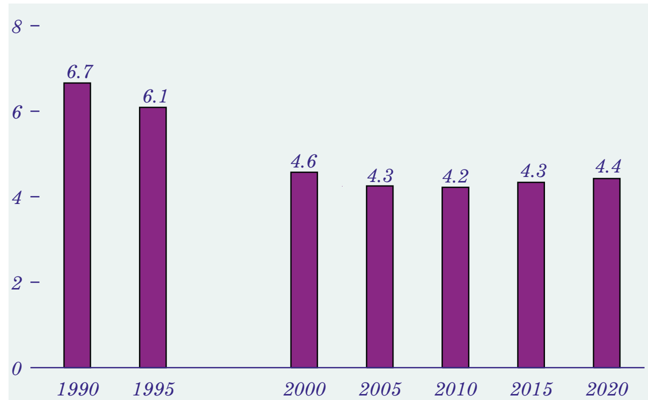
CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year may not be reached until after 2010. About 97 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by most generators, as only about 12 gigawatts of capacity had been retrofitted by 1995.

In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants are tightened, and limits are set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are projected to decline from 11.9 million tons in 1995 to 11.5 million in 2000 (Figure 128). With the SO_2 emissions cap tightened in 2000 and after, the price of allowances is projected to rise, reaching $215 per ton by 2005. As the price rises, 11 gigawatts of capacity—about 37 300-megawatt plants—is expected to be retrofitted with scrubbers to meet the Phase 2 goal.

A Significant Drop in Nitrogen Oxide Emissions Is Expected in 2000

Figure 129. Projected nitrogen oxide emissions from electricity generation, 2000-2020 (million tons)



Nitrogen oxide (NO_x) emissions from electricity generation in the United States are projected to fall significantly over the next 5 years as new legislation takes effect (Figure 129). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months. The CAAA90 NO_x reduction program called for reductions at electric power plants in two phases, the first in 1995 and the second in 2000. The second phase of CAAA90 is expected to result in NO_x reductions of 0.8 million tons between 1999 and 2000.

Even after the CAAA90 regulations take effect, further effort may be needed in some areas. For several years the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force the coal plant operators to reduce their emissions more than required under current rules.

The interpretation of ozone transport studies has been controversial. In September 1998 the EPA issued a rule, referred to as the Ozone Transport Rule (OTR), to address the problem. The OTR calls for capping NO_x emissions in 22 midwestern and eastern States during the 5-month summer season, beginning in 2003. After an initial court challenge the rules have been upheld, and emissions limits have been finalized for 19 States.